COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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| In the Matter of: | ) | |
| | ) | |
| Preparation of the 2007 | ) | Docket Nos. |
| Integrated Energy Policy | ) | 06-IEP-1I & |
| Report (2007 IEPR) | ) | 06-IEP-1J |
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, MAY 24, 2007

10:00 A.M.

Reported by:
John Cota
Contract No. 150-04-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

Jeffrey D. Byron, Associate Member

ADVISORS PRESENT

Melissa Jones

Kevin Kennedy

Suzanne Korosec

Tim Tutt

STAFF and CONTRACTORS PRESENT

Sylvia Bender

Denny Brown

Tom Gorin

Lynn Marshall

Belen Valencia

Lorraine White

ALSO PRESENT

Richard Aslin, Pacific Gas & Electric Company (PG&E)

Arthur B. Canning, Southern California Edison

Tim Vonder, San Diego Gas & Electric

Greg Katsapis, San Diego Gas & Electric

Nick Zettel, Redding Electric Utility

Mark R. Minick, Southern California Edison

Curt A. Hatton, Pacific Gas & Electric Company

# I N D E X

P R O C E E D I N G S

10:07 a.m.

PRESIDING MEMBER PFANNENSTIEL: This is the Integrated Energy Policy Report workshop on the 2008 Peak Demand Forecast and the Summer of 2007 Electricity Supply and Demand Outlook.

I am Commissioner Jackie Pfannenstiel, I am the Presiding Member of the Integrated Energy Policy Report Committee. To my left is Commissioner Byron who is the Presiding Commissioner on the Electricity Committee. To my right is Commissioner -- no, I'm sorry, an empty seat. To my right is Melissa Jones who is Commissioner Geesman's Senior Advisor. And since Commissioner Geesman was not able to be here today Melissa will represent Commissioner Geesman. And to Melissa's right is Suzanne Korosec who is Commissioner Geesman's other advisor.

With that why don't we turn it to Sylvia. Are we going to begin?

MS. BENDER: Yes. I am Sylvia Bender. I am the acting deputy director for the electricity supply analysis division and I am just going to run through, first of all, our little opening remarks we have here, our housekeeping duties, and then let you know who is going to be presenting the various parts of today's workshop.

For those of you who are not familiar with this building the closest restrooms are located across the lobby out there down to your left. There is a snack bar on the second floor under the awning. Lastly, in the event of an emergency and the building is evacuated please follow our employees to the appropriate exits. We will reconvene at Roosevelt Park located diagonally across the street from this building. Please proceed calmly and quickly, again, following employees with whom you are meeting to safely exit the building.

To begin our workshop today we divided this into two parts. The first part will be the 2008 Peak Demand Draft Forecast that will be presented by Lynn Marshall and Tom Gorin. And at the conclusion of that portion of the workshop we'll them move into the Summer 2007 Electricity Supply and Demand Outlook that will be presented by Denny Brown.

So Lynn, if you're ready to start we'll go ahead.

MS. MARSHALL: A few comments about why

are we doing this today. Probably what we're presenting is our proposed peak demand forecast for the summer of 2008. The primary use of this is going to be to provide a forecast for the IOU service areas that will serve as the reference case for 2008 resource adequacy.

So in the PUC resource adequacy proceeding they have decided that the CEC forecast is in effect the control total. So to the extent that the sum of the LSE forecasts deviate from our forecasts by more than one percent their forecasts are going to be adjusted ultimately to within one percent of the CEC forecast.

However, we are also presenting our updated, our analysis of 2006 weather normalized loads and 2008 forecasts for the rest of the ISO and the for the non-ISO parts of the state.

And the reason those are important is our forecast does get used not only in the Energy Commission energy policy analysis but it's also used by the ISO and the PTOs in their expansion plans. The ISO uses our 1 in 10 forecast for their LCR studies. And they don't just look at ISO jurisdictional. They include the non-jurisdictionals, SMUD and LA.

So we're interested in getting comments on our methodology and our analysis for all of those areas.

Additionally, our analysis of 2006 is going to serve as a starting point for our forthcoming, revised Ten Year Forecast that we expect to be publishing next month for a workshop in July.

So to summarize what we're doing is, analyzing loads and temperatures in 2006 to come up with weather normalized load for each utility area. We're using the growth rate from our last adopted forecast of 2005 IEPR.

Generally for PG&E and SDG&E we've got revised up on the order of one and a half percent. And Edison we found less load growth than we had forecast and so the Edison forecast is going down.

For the POUs we have not revisited those forecasts since September 2005 IEPR. We analyzed the IOU service areas only last June to support the 2007 Resource Adequacy Process.

So we have smaller changes for the IOUs. However for most of the POUs we see some pretty big changes just because it's been so long since we've updated our forecasts. So we now have a consistent set of updated peak starting points.

This shows the 2006 growth rates and the change in our analysis for 2006. And we're going to go through today each of the results for each of these areas.

And following our presentation then we'll give each of the utilities an opportunity to comment and make their own their own presentations.

Generally for our methodology we're using two weather statistics that were regressing on afternoon peak demand for each area. We've collected data from each of the utilities on the actual interruptions that took place last summer, demand response and interruptible load curtailments.

And we used a three-day, weighted maximum temperatures, 60 percent today 30 percent yesterday, 10 percent the day before. This table shows the weights for the weather stations, how each weather station is weighted. These weights are based on the distribution of air conditioning saturations from our Residential Appliance Saturation Surveys.

For some areas, Edison in particular

were using a diurnal spread variable. So it's the difference between the min and the max for each day. And to some extent it's a proxy for humidity. It also captures the fact that when you have a lack of overnight cooling.

So we're using that in southern California. And in PG&E we have not found it to be significant.

I think I'll show the next graph first. This shows the 2005 and '06 daily peaks plotted against those PG&E weighted maximum temperatures. And you kind of see when we were doing our 2005 analysis, 2005 was a very cool year so we had a lot of uncertainty temperature about what the temperature response was going to be at higher temperatures.

2006 we're able to validate the weather stations we're using. And we get revising our forecast up about 1.6 percent

I should mention that in the report we do an analysis of the debate we had last year over the various weather statistics that should be used between us and PG&E.

And in those graphs we refer to PG&E weather stations. And that's not really a PG&E

forecast. That's our illustration of the alternative methodology that was discussed last year. So that's not a PG&E forecast. They actually have a different methodology they're using this year I understand.

So to go back to the previous table that shows the results, those are revised 1 in 2. And for each of the 1 in 5, 10 in 20 cases we've included those multipliers for the hot weather scenarios have gone up just a little bit from about, I think the 1 in 10 has gone up from about three and a half percent to maybe 3.7 by inclusion of 2006 in our weather history.

And we'll come back to the 1 in 10. So to evaluate how well the weather statistics that we're using are predicting or, this shows the regression coefficients that we estimated using the actual temperatures that occurred plotted against the actual peak demands.

And for the 2006 the fit is pretty good. We have a standard error of I think about 2.5 percent on a year ahead basis when we're using last year's coefficients and then using a growth rate that adds some error not surprisingly. So we have a standard of about 3.5 percent. And that's pretty typical I think for most of the IOUs modelled results anyway.

The PG&E service area that we're using don't cover, those are PG&e bundled and direct access customers only. So to update forecast for the rest of northern California we used hourly loads from most of the LSEs as provided to us. Some of the smaller ones we're having to estimate from energy use.

But this shows the updated forecasts for each of those. Probably the most notable one here is Silicon Valley Power where there was, we found 2005 to '06 growth I think six or seven percent. Pretty significant growth which is consistent with their forecast. They've been seeing that for several years as vacancy rates in their areas declined.

In most of the other areas the growth rate was similar '05 growth rate was similar to PG&E, maybe one to two percent.

So I'll talk a little bit about how we do the 1 in 2 versus the 1 in 10. So this is a distribution of using our 2006 regression coefficients. We run it through all of our 56 years of weather data to come with a predicted daily peak.

And from that we extract a predicted annual maximum. And so we've ranked, they're now in rank order here.

The 2006 predicted annual peak, you can see there that's the second highest out of the 56 years. And it's higher even than our 1 in 20 point. So it clearly was an extreme event.

So the 1 in 2 is the median of these predicted annual peaks. And the 1 in 10 is about approximately the sixth highest peak.

Now this methodology is in effect assuming that this is a population of possible outcomes. And some utilities have pointed out that this is really a sample because this is all the data we have right now. But there's lots of other things that have happened in the past and possible future outcomes.

If you treated this as a sample from assuming we say on the graph normal distribution. Actually for this example we used a T distribution which is similar, normally distributed.

You get a higher if you look at the red line, you get a much higher 1 in 10. It goes from 3.6 percent to something like six percent. And you're setting the 1 in 10 at a level that we actually have only seen, that has only been exceeded in three of the last 56 years.

I think we're probably going to come back to that topic as the utilities make their comments.

One of the things that you can see from this and I guess I'll talk about this one. There is most of the annual maximum temperatures are there clustered within the center. And you have a relatively few very extreme events.

So it's not clear from looking at this chart that this is obviously normally distributed. So the alternative methodology is pretty different results.

Our Edison forecast and these are the 2005 and '06 daily peaks plotted against the daily maximum temperatures. We do also us a diurnal spread variable.

What we found for the Edison area in 2006 was essentially no load growth. That's in a big contrast, we have the 2004 point down there. We saw a lot of load growth from '04 to '05 and in the last few years as we're rebounding from the effects of the energy crises and tech bubble.

There has been a lot of growth. But we just in these data we don't see any growth at all in '05 and '06.

So as a result we're revising our forecast down actually. And as you can see from this table, we have the forecast that Edison has submitted. And actually for this forecast I've included their planning area forecast that was in their long term procurement plan filing because it's on a comparable basis.

So we have a big difference their that we will come back and talk about more when Edison makes their comments.

We are not seeing a continuation of the load growth that we have in recent years.

Okay here's a measure of our actual daily peaks versus our model's prediction. And again it's the 2006 regressions have a standard error of around 2.5 percent. Our year ahead forecast method adds about a percent to that.

For the disaggregation of the Edison planning area forecast, Edison's planning area loads include all the resale cities and MWDs. So we tried to do more accurate breakdown of that. So we haven't revisited the Anaheim, Riverside

Vernon loads et cetera in a couple of years.

And you can see they're a lot higher. But we went through each one of those either using FERC data or hourly loads from their settlement data and estimated a weather adjusted peak. So I think we have a more consistent set of disaggregation.

The sum of these were within a fraction of a percent of our planning area total. So we did not have to apply a big calibration factor to get these to sum up nicely.

Which I would say in 2005 was not the case. We had a really big calibration factor to do this. And the problem really was our planning area forecast was too low. And that's why you're seeing now we're able to, we're revising the POU forecasts up.

And this is a graph similar to how we showed the PG&E annual predicted maximum temperature distribution. So we have our, the 1 in 2 is the median, you can see 2006 there is just under our 1 in 10 level. So in the Edison area last year was about a 1 in 8.

Here we've plotted the ten year averages through history in the Edison area. And I think it's interesting to note that they move around a lot. So people talk about global warming it's not obvious, 2006 is one data point that we had a similar event both in PG&E in 1972. But there's not an obvious upward trend.

There appear to be cycles and there are some weather phenomenon that could be associated with those cycles. But we don't see an obvious time over the whole 50 years of data we're using.

This is the distribution of annual temperatures. Tom do you want to talk about San Diego? The San Diego weather puzzle.

MR. GORIN: I want to go back.

MS. MARSHALL: You want to go back?

MR. GORIN: This is different. These are the same charts as in the other presentations. San Diego presented some interesting problems this year in trying to figure out what exactly was going on.

They actually peaked on a Saturday. Which utilities aren't supposed to do. But since they did that it made for some interesting conversation.

The fit was not as good as it has been in previous years using the typical temperature variables. And the representative from San Diego may want to go into that too. Because I've had discussions with him. And he's using more variables than just temperature and diurnal variation.

This is a scatter plot of the top temperature days. And there's a couple interesting things to note here. The blue, there's a lot more blue dots than there are pink dots from 2005.

The highest combined temperature was 91 degrees which probably felt good to people down there.

Another interesting note is that the last Tuesday in June was the second highest temperature of the year the way we calculated it. And it appeared to be the first warm day of the year.

And so the load was disproportionately low to the temperatures. There's also another point.

The day after Labor Day September 5th was kind the end of a little heat aberration in San Diego. And it was almost the last hurrah of heat there. So that gives you a higher load.

So trying to figure out peoples' behavior and their air conditioning use around the temperature patterns that we saw last proved to be a little difficult.

This is a, reports the results compared with San Diego's were, the 2008 forecasts are relatively close. Weather normalized values are relatively close.

There is more variation using the regression results. You can see the, the regression results greatly overpredict the first hot weather period. They're fairly good on peak. And they underpredict the last hot weather spike.

So I would venture to say if we did this on annual basis we'd be, actually for San Diego we have data for 1979 to 2006. This would not be a typical pattern of San Diego weather that you would probably see.

This is the same type of distribution for San Diego. It's limited to 1979 to 2006. There's a lot smaller variation between the two methods of estimating the 1 in 10 scale.

You can see 2006 is more toward the center. There have been hot periods in San Diego prior to when we have FERC loads for. It would actually be interesting to see what the actual and maybe prior to when a lot of people had air conditioning down there.

Now I think in all of the southern California utilities there's a lot of air conditioning all the way up to the ocean. So when the sun comes out and it gets hot people can use it.

This is really the 27 year chronological temperature ten year averages. It shows a similar pattern to Edison. Both the Edison and the San Diego annual, this is a combination of El Cajon, Miramar and Lindbergh Field a composite temperature that we used.

They're more uniformly distributed than the PG&E distribution I think. And I went back to Lindbergh Field because we have a longer history. And you see the same kind of variation.

There's cyclical patterns, maybe not cyclical patterns but there's patterns that happen for, I'm sure we can understand what the reason for them happening was. I'm not sure that we can forecast what the, when they're going to happen again.

And this is the distribution of

Lindbergh temperatures from 1959 to 2006. And you'll notice that in two years it was, they had incidences of 100 degree three day weighted average temperature there. But they were back in the 50s and 60s as I remember it.

Our analysis for SMUD, similar scatter plot. There was a, we raised, there was greater temperature response in 2006 than there was in 2005.

You can see that in 2006 you can actually see the load starting to tail off on the top end. It never reached a point where it flattened out which would kind of indicate that all of the air conditioners were running 60 minutes an hour and the load was fully saturated.

But it looks almost like at a point of about 105 degrees and if you could turn the slide sideways and look at it lengthwise you can actually see the S shape to that curve.

We've been trying to figure out where, if there actually is a point at which load flattens out. And I've done some work even with the Arizona utilities and they keep growing at high temperatures. Maybe at a decreased rate but it doesn't seem that there's actually a saturation point that we've been able to reach yet.

We have fairly large difference between our forecast and the SMUD forecast. I've been talking with the SMUD forecaster about it.

Maybe in the way we represent temperature we use the Executive Airport. They use a combination of Executive Airport and downtown. We're going to look to see how much difference that makes.

Our forecast is really focussed on annual peak. And theirs is more on day-to-day load forecasts. So theirs is oriented towards even hourly and daily loads.

So we're going to try and resolve those differences. We have a fairly good fit of the actual versus predicted. We over predict I think the holiday periods. Which may mean that sometimes in the holiday periods people leave town here. They get out of the service area. They go where it's cooler.

The same peak distributions for SMUD. Using the normal distribution gives you a slightly narrower band. But you can see there you know 2006 was about a 1 in 10 event in SMUD. Where you know there are two years where temperatures were a lot worse than they were last year.

This is again the ten year averages of SMUD temperatures and the annual averages. And I think they're relatively random. But they're pretty tightly clustered in the middle between a 103 and 106 degrees.

If you said that's what the maximum temperature in the summer year was you'd be pretty accurate in a guess.

L.A., we visited for the first time in a while. The L.A. loads at higher temperatures were a lot more diverse this year than they were last year which we're trying to pin down why that is. It may be a function of the weather stations we use versus the ones that are available and the ones that L.A. uses.

They use the Civic Center. We actually use Long Beach and Burbank and a combination of those because they were airports that had a 50 year history.

They noted in correspondence with them that they use the Civic Center and actually in '98 the Civic Center changed and that increased the temperature in downtown L.A.

And we're trying to figure out how we would adjust for that for considering what normal is.

Our forecast is almost seven percent higher than L.A.'s forecast. We're still kind of in the process of discussing with them what the differences are and may make some revisions to it.

This is another actual versus predicted After the peak of the summer the predictions were not as good as they could have been for the three days surrounding the peak of the summer. And I guess that's it. Questions?

PRESIDING MEMBER PFANNENSTIEL: Commissioner Byron, questions? None at the moment. Thank you Tom.

UNIDENTIFIED AUDIENCE MEMBER; Tom were all those temperatures --

PRESIDING MEMBER PFANNENSTIEL: Excuse me, if you're going to ask questions I think you need to go to the podium so they can capture the.

MR. KATSAPIS: Tom just real quickly. All the temperatures you're presenting, are they on the 631 basis?

MS. MARSHALL: Please identify yourself.

MR. KATSAPIS: Greg Katsapis of SDG&E.

MR. GORIN: Yes I believe they are. We use the weighted average maximum temperature that Lynn described earlier. In order to shorten the name of it that's the maximum temperature that we referred to.

MS. MARSHALL: Next we'll have PG&E make their comments. Let's see, here it is. Just hit that to page down. Let's get the lights down here.

MR. ASLIN: Good morning and it's a pleasure to be here. My name is Richard Aslin and I work for the Pacific Gas and Electric Company. And I head up the economics and forecasting team.

And one of the things that we do is produce the PG&E System Peak Load. I just wanted to check and make sure that I'm using this microphone properly.

MS. MARSHALL: Yes.

MR. ASLIN: Okay, thanks. So what I'd like to do is, I just have a few slides. I have to say right off the top that those slides were available when you walked, it's not the full package that I have here.

That package of slides was based on some discussions that Lynn and Tom and I have had over the last couple of weeks. And I added some slides after I picked up the actual report. So there's a few extra slides. But those will be available on your website.

I just have a couple of primary themes. One is that I would like to express that PG&E really supports the IEPR process. We think it's a good process. And we think it does result in better forecasts, better understood forecasts and forecasts that people can buy into. So we do support the process.

And I'd also like to thank Lynn and Tom for all the work that they've done. They've been very helpful over the last several years in helping us to improve our forecasts.

And the other thing, once I get into the presentation I, there I really have just a couple of themes also.

One is kind of anti-climactic in terms of the actual workshop which is that for the most part we pretty much agree with the CEC's 2006 and 2008 projections for PG&E.

But the bigger thing that I'd like to talk about is load forecast uncertainty. Because I think that's a real issue going forward and probably ties in a little bit better with the second presentation than the first from the CEC on 2007 Summer Outlook and going forward.

So with that I will move on. As far as the 2006 summer loads go based on the information we have from the CEC staff we don't have any major differences in what temperature normalized 2006 loads would have been.

We don't know exactly what they would have been. As Lynn pointed out the error variances, you know 2.5 to 3.5 percent which translated into megawatts is 500 to 700 megawatts.

But on an expected value basis coming in about one percent, within one percent of the CEC's estimates. But then that's what I would call consistent.

Just as a little kind of factoid, the PG&E did a lot of work after the, well leading up to and after the workshops that we had last year after the summer heat storm which were very, very beneficial, by the way, and as part of that work we did kind of hone in on what was this recurrence interval event for PG&E service territory the 2006 summer heat storm,

And we place it somewhere between a 1 in

30 and a 1 in 40 type event. But one thing that we should keep in mind and one of the questions that was asked I think repeatedly after the summer heat storm event because we did have a lot of meteorologists, we did talk a lot about climate change and one of the things that we should keep in mind is that what, this is 1 in 35 relative to the historic period 1960 to 2005.

And the real question is are we going to start seeing those types of heat storm events more frequently going forward. That's the real question for me.

And if we take a look at some fairly recent studies that were done by the California Climate Change Center the answer to that question is, yes.

So what we've seen here is a graph and what it's doing is it's showing the historical maximum hourly temperatures in degrees centigrade for a average of San Jose, Sacramento, Fresno and Los Angeles.

And what you can see is that in the historic period 1961 to 1990 it was not exactly the historic period that we're using but you know, close just to give you an idea. In that historic period the average temperature calculated there maximum temperature is much lower than it is if we move to the next period which is 2005 to 2034.

And as we move further and further out in time over the century that just keeps increasing and increasing.

So I would like people to take away from this and think about is whether what we are currently calling a 1 in 5 or a 1 in 10 is really if we believe the climate change models and if the downscaling of these global climate change models to our service territory climate are correct. That will actually be the 1 in 2 going forward. That's something to think about.

PRESIDING MEMBER PFANNENSTIEL: Rich as we think about that, are you, is PG&E actually using these higher temperatures then in your going-forward forecasts?

MR. ASLIN: Actually what we've done is we've started to work with the National Center for Atmospheric Research in Boulder to develop a temperature series that does incorporate this downscaling of global climate change.

It's not completed yet. And we're hoping to have it for the next forecast cycle.

But we don't have it done right now.

PRESIDING MEMBER PFANNENSTIEL: Thank you.

MR. ASLIN: So just going to the 2008 load projections. Also there for 2008 based on the information from CEC staff, our 2008 forecast for PG&E service areas is also consistent with the 2008 projection that's out there right now.

So we're within one percent. We're actually even closer there than we were on the historics. So we're really between, we're within a 100 megawatts.

But that's only looking at the 1 in 2 recurrence interval temperature forecast. And one thing that I would like to be able to discuss with staff going forward is that we do have a pretty big difference between our analysis and the staff's analysis when it comes to more extreme temperature events.

So, for example, when we calculate our 1 in 10 recurrence interval forecast we end with a forecast that's about six percent higher than our 1 in 2 forecast.

And if I understood the CEC's forecast correctly what they're ending up with is something that's about 3.7 percent higher. And that's a difference of about 500 megawatts.

And the thing as Lynn has pointed out 1 in 10 forecast is starting to be used in more places. So it would be good if maybe we could focus in this round of the IEPR on trying to gain some consensus around what that recurrence interval, the 1 in 10 in particular, hopefully even the more extreme temperature recurrence intervals we can get some consensus around that.

Because we're pretty different on that. And just to give you a frame of reference --

ASSOCIATE MEMBER BYRON: Excuse me can you characterize what you attribute that substantial difference to?

MR. ASLIN: I actually attribute it to the fact that Lynn and Tom were talking about how they have gone to this temperature statistic which was four temperature stations which were weighted I think on air conditioning saturation.

And I'd have to say that after the summer heat storm event and the workshops and everything we also went to work on the temperature statistic.

And what we're using now is an 11

station statistic which is weighted by summer and winter sales. But we're also using the min and the max. We're actually using the average but that includes the min and the max.

And what happened was that as soon as we started to use the average temperature what we started to see was the dispersion between the 1 in 2 on an average temperature basis using those 11 stations.

And the 1 in 10 for those 11 stations on an average temperature basis was actually pretty large. Much larger than just using the maximum temperatures. So that's what I attribute it to, really just rethinking the temperature statistic and starting to include the minimum temperature into the picture.

Because I have some slides on this. They're in the package. But I don't want to really bore people with this.

What we really found was that in northern California we also have this sort of same thing as what Lynn and Tom were explaining. In southern California it's a humidity effect where you don't have a big dispersion between min and max.

But we also see that in northern California as you start to move to the more extreme temperature events. What happens is the maximum temperature really doesn't keep going up and up and up. But the minimum temperature really goes up. And so that increases load. Does that answer your question?

ASSOCIATE MEMBER BYRON: Yes, thank you.

MR. ASLIN: Okay. And just to go back to climate change for just a second to also give some perspective. So the California Climate Change Center also produced a report very recently where they really looked at the effect of climate change on electric consumption going forward.

And what they found was that using certain scenarios and actually this A1Fl scenario or Fi scenario, it's kind of a mid-range scenario. It's not the most extreme scenario. It's very much mid-range.

And what they were finding was that according to their models what we should expect relative to this historic period 1990 to, I'm sorry, 1961 to 1990, that the temperature statistic based on that if we move to a temperature statistic that was based on downscaling the global climate change models what we would expect is to see an increase in the peak demand at the 1 in 2 level of about 4.8 percent.

And 4.8 percent is a pretty large amount of megawatts. It's like a thousand megawatts.

ASSOCIATE MEMBER BYRON: So just to make sure I understand this table here. The peak demand annual percentage increase is 4.8 over each of those years.

MR. ASLIN: Well I was just saying, if we, if you calculate your temperature statistic so your benchmark temperature for the 1 in 2 level and you use the period 1990 or 1961 to 1990, that historic period, and you run your model and then in the next step you calculate a new benchmark temperature based on downscaling of global climate change models, and you run that exact same forecast model over that, the result will be that your peak demand would be 4.8 percent higher using a temperature statistic that incorporates the global climate change downscaling.

And I'm not saying that's the truth or anything. I'm just saying that's something we should really think about. Because that's a thousand megawatts of load uncertainty over the next couple of decades, three decades, that we should be aware of. And try to incorporate in some way into our thinking.

So again the key messages that I wanted to put out there for today was that in terms of both the 2006 temperature normalized load and the 2008 forecast peak load, we're pretty much really consistent with the CEC staff's ideas around those.

And that's again on the 1 in 2 level but that when it comes to these more extreme levels for the forecast, the 1 in 10 and so on, we differ. And to put some perspective around that.

The ISO had an estimate in a very recent publication. And they estimated that the NP 26, 1 in 10 scalar was 6.5 percent. And I mentioned earlier PG&E's model now shows six percent.

And also if I remember correctly the Southern California Edison scalar for 1 in 10 is close to nine percent. The San Diego Gas and Electric scalar is close to nine percent. I think I saw the LADWP scalar was around nine percent.

But PG&E's is still down there in the 3.7 percent range. And I just, and again, I'm not saying that that's wrong either. Because one of my messages here is about load uncertainty.

But I do think if we could focus on trying to get some consensus around that going forward that would be beneficial for the forecasts.

And I think that's all I have to say. There are other slides in the presentation so if anybody has questions on those they can certainly give me a call or send me an email or something. But that's it for now. I'd be happy to take any questions.

PRESIDING MEMBER PFANNENSTIEL: Let me just pursue that a moment because it is a big difference, the difference in PG&E's estimate and the staff estimate on the 1 in 10 compared to the 1 in 2. Those are fairly significant differences in terms of the load impact.

And what are you, what's the difference? Is it as you said before the difference in the reporting areas or the temperature, I mean how do we get, how do we peel that back?

MR. ASLIN: Well, what I think the most productive thing to do right off the top would be for us to get together and try to develop a common temperature statistic that we're using.

Because right now my guess is, well we used to actually get that same 1 in 10, I can tell you that. We used to get the 1 in 10. It was about four percent bigger than the 1 in 2. And that's because we were just using the maximum temperature.

PRESIDING MEMBER PFANNENSTIEL: So it really is that the difference between maximum and minimum you think that that's a different way of doing the calculation.

MR. ASLIN: Yes. And I think that's really why, and I'm not sure exactly how the daily dispersion is factored into the 1 in 10 and the 1 in 20 temperature statistic. But that's not used for PG&E. So for Southern California Edison for San Diego Gas and Electric and for others the minimum temperature is being incorporated into the recurrence interval temperature statistic.

But for PG&E I don't believe that is the case. So I think we --

PRESIDING MEMBER PFANNENSTIEL: Right I thought Lynn said before they didn't find that to be significant? Is that correct?

MR. ASLIN: Yeah, I think that might be true if you look at any individual year. But I think that when you start to look at the temperature statistics themselves over a long period of time that doesn't tend to be the case.

But I think it's something to explore. That's really my request. That we could explore that further.

PRESIDING MEMBER PFANNENSTIEL: Important, Tom did you have a comment on that?

MR. GORIN: Well --

PRESIDING MEMBER PFANNENSTIEL: Green light on.

MR. GORIN: Green light on. It's something that I think we need to explore the differences in weather stations and how they're weighted with PG&E.

There's another difference between PG&E and the southern California utilities in that there's a lot less air conditioning in the Bay Area in PG&E. So there's not a lot of ability to respond to hot temperatures, unlike the southern California utilities.

I mean it may be that if it continues to have, continues to be hotter in PG&E, in the Bay Area for short periods of time, people may start to put air conditioning in.

They're doing that in the northwest on the coast. But I'm not, I think that's part of the difference in the reduced percentage of recurrence interval for PG&E is if next year if it's hot for a week in San Francisco they don't really have the ability to respond to it unless Home Depot runs out of air conditioners.

PRESIDING MEMBER PFANNENSTIEL: What year graphs are you using? Is it a recent?

MR. GORIN: It's the 2002 that's the most recent we have.

PRESIDING MEMBER PFANNENSTIEL: I suppose it is possible that air conditioning saturation has increased since 2002 in some of the key parts of the PG&E area?

MR. GORIN: We've reweighted using the 2002 graphs for PG&E. I think our assumption now for PG&E is about seven percent of the San Francisco Bay Area has air conditioning of the households.

It's a much larger portion in the San Jose region. But it's one thing that we would need to keep a watch on. But I think --

MS. MARSHALL: One of the things we did was look at, we got from the ISO we got greater

Bay Area versus Non-Bay Area loads and you can see the blue line is the temperature response in the greater Bay Area.

And you can see it's just a lot lower slope.

PRESIDING MEMBER PFANNENSTIEL: One would expect that it would be a lot lower. The question is whether it's changing over time based on the structural change in the appliance use in the Bay Area which has obviously more people but presumably fewer air conditioners.

But if that's changing then that would of course affect the results.

MS. MARSHALL: Yeah, but I think one of the differences, other differences between PG&E and Edison is a greater diversity in the climate regions. So you have this big, if we do an analysis of the 1 in 10 temperature for each of these areas separately, yeah, it's around six percent.

But when we do the whole of northern California jointly, it's 3.6 percent. So the diversity in the temperature and the lack of coincidence there is offsetting. And that's why I think you see relatively few extreme temperature events in the PG&E area as a whole.

PRESIDING MEMBER PFANNENSTIEL: Did you have a comment Rich on this?

MR. ASLIN: Yeah, thanks for reminding me of that. That's was one of the things I wanted to bring up actually. One thing that happens is as you move to more extreme temperature type events you do lose diversity.

So it is true that naturally PG&E's service territory has a number of micro climates. It's 50 to a 100 or something according to our meteorology team.

But as we move into more extreme heat storm events you lose that diversity. So you start to, that's what happens in all extreme events. You lose diversity and all of a sudden things start to happen in ways that you couldn't really envision just using the averages.

So, again I just think it's something we need to explore. All the other ones and tens seem to be very high relative to PG&E's. And again the ISO, I don't know exactly what temperature statistic they use but they came up with a 6.5 percent 1 in 10 over the 1 in 2. So it's something that we need to explore. That's all I'm asking.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Other questions?

ASSOCIATE MEMBER BYRON: You know I can't help but think that because you are doing this and that you're doing this forecasting differently than you have in previous years. That there's a, you know, a reflection of a corporate philosophy change here as well. And that's probably in my mind that's factoring into your thinking somewhat as well.

I agree, I don't know if I'm saying that properly. But clearly there's been some changes in the way PG&E thinks about climate change. And the way you're now doing your forecasting is differently than it's been done in previous years.

MR. ASLIN: I agree with that. We have really accepted that global climate is something that we need to start to understand and adapt to now. And, yeah, so last summer was a real wake-up call.

And we took a lot of steps to try to beef up our analysis of temperatures, our understanding of the effects of temperatures. And we're going to keep doing that. So, yeah I agree that that's definitely true.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Are there other questions? Thank you.

MR. ASLIN: Yep.

MS. MARSHALL: Edison, we'll have comments now from Art Canning of Edison. There you go. So you can just page down.

MR. CANNING: Page down.

MS. MARSHALL: Down there, there.

MR. CANNING: Good morning commissioners, my name is Art Canning from Southern California Edison. Staff it's nice to see you here again and talk to you again.

Now which button was it here?

MS. MARSHALL: It was this one.

MR. CANNING: Oh, okay. Here we go. Well Rick Aslin said he didn't have a big issue with the staff forecast. We do.

And as you can see on the board there our long term procurement plan forecast is twelve hundred and thirty-seven megawatts higher than the staff forecast for 2008 for the research adequacy part.

That's 5.4 percent. If you'll remember the staff was using a 1.5 percent for us. So that's three and a half years worth of growth or one large generator. So it's a significant difference.

Now where is the difference coming from? So one part is the starting point. So when we did a weather adjustment of 2006 summer we come up with about 23,000 megawatts as the weather adjusted number.

The staff did an analysis and came up with a 22,417. So that's 580. So that's about half the difference of to the starting point. And not surprising the other half is due to the growth rate.

The footnote down at the bottom here was that the staff last year in weather adjusting 2005 found 2005 was 22,442. So actually they showed a decline from 2005 to '06.

But when I read the micro print in the analysis they reanalyzed 2005 and lowered it to 22,317. So actually there was a little bit of growth.

But it always seems like everything just keeps going down. So and that's really the frame of the staff analysis with Edison. It just seems like they're a lot lower than us in a lot of different places.

In the growth rate, the other half of the source of difference. We've got about a two and a half, 2.8 percent growth rate. Staff is using 1.5. And 1.5 comes from the September 2005 California Energy Demand CEC Report from the staff which is getting a little bit old, a little long in the tooth perhaps.

Lynn I'm going to quote you as saying, you're not seeing the load growth continue at the rate that it has the last several years. Well I'm going to put some words in your mouth.

You're using 1.5 percent which is a two year old number. Now unless you've done some IEPR for 2007 analysis it says, we're still only growing 1.5. What you really should say is you assumed 1.5 and we really haven't looked at whether it's still a good number or not.

MS. MARSHALL: Yeah, well I was referring to the '05, '06. Lights, is this on?

MR. CANNING: Okay, '05, '06.

MS. MARSHALL: Yeah, I was referring to the fact that from 2005 to 2006 we have not seen that any level of growth.

MR. CANNING: Great, I got it. Thanks,

I understand. That's a different point then.

Okay, next page. This one comes out of the long term procurement plan reply comments Edison made. The time change is different.

I'm looking at 2004 to 2011. And I just wanted to say that well that I made the point that the energy forecasts are about the same growth rate between staff and Edison. But the peak demands are quite a bit different.

Edison has quite a bit higher peak demand forecasts than energy forecasts. And what this means is a declining load factor. You're becoming more peaky.

And it's not the way we make the forecast. But it's a metric that comes out of making the forecast.

So this could be happening. Peak demand is growing faster than energy for a number of different reasons. And we can talk about those.

But the main thing is it seems to be a difference in the staff outlook and ours. And the load factor again, I'll go to the next page. I think we're plotting that.

Here's the recorded and weather adjusted load factor. And load factor is the average hourly demand divided by the peak hour demands. There's always going to be a ratio under a hundred percent.

And you can see the heavy dark line is our estimate of what the weather adjusted load factor was. And it was running there a little above 65 percent and then it seems somewhere in the late '90s it started trending down.

The white circle dots are the recorded numbers. And those definitely show a trend. But the weather adjusted is what I would go by.

We think it's a trend. And we think it's going to continue. Now again it's not how we make the forecast but it what comes out of it.

It's happened before. This one goes all the way back to 1952. During the 50 to 1970 time period we were winter peaking. And we're up there way up there at 65 percent load factor.

Our first summer peak you can see is when we in '69 and then '70 and '71 was when that load factor starts dropping for a decade. So for 10 years when the peak demand was, the summer peak was growing so much faster than energy we have to solve the climbing load factor.

And then it just makes another turn

right around 1980 and stays essentially flat for another 15 years it looks like.

I've never been able to model what it was. I mean I know people moving inland, air conditioners a lot of things going on. But it's not fair to show a winter peak historical back in the 50s and 60s and it's a summer peak.

But in any case a long term or a declining load has happened before. So it could be happening now. And we just point to that as one possibility. We believe it. We believe that it is going down and it'll continue to go down for a few more years.

ASSOCIATE MEMBER BYRON: Do you have a reason for why you think it's going to continue to go down other than just looking at data.

MR. CANNING: We don't have any model results. What we look at is when we talk about it and this is partly a judgement call. A lot of what's happened since 2000, people have taken a lot of money out of refinancing the house and rebuilding homes, especially along the beach communities.

Where now they're putting in two story homes with air conditioning. My next door neighbor is that, a 1943 twelve hundred square foot house is now a 2006 twenty-six hundred square house. It's probably got three times the cubic space and it's air conditioned.

Now he's probably only going to use that on a few days a year relatively in Long Beach. So what it'll do is tend to make the peak demand even peakier. In other words he won't turn it on at when system effective temperature is in the moderate range but the very, very high range when Long Beach finally gets hot. And then he's going to turn it on.

We don't have good statistics on how many houses are remodelled. That's what we've been trying to get out. We did find how much money was taken through refinancing from 2000. It's just humongous amounts of money was taken out nationwide and in California, people taking equity out of their homes.

We noticed that construction employment seems to go up even when the number of housing units, faster than the number of new housing units going up. But we don't have a good number on remodels. I think that's a big part of it.

PRESIDING MEMBER PFANNENSTIEL: Do you

have numbers on air conditioning saturation, central air conditioning, size of home, those kinds of statistics?

MR. CANNING: We know the homes are getting larger. And I don't have that statistic with me. But it's gone from like twelve hundred, it's gone up by a couple hundred square feet over eight years or ten years. I don't think it's, it's something about a fact, most homes are being built out in the eastern end of our service area. San Jacinto Valley is a big growth area which is very, very hot. So that's having some effect.

But again, we've been building new homes in the hot areas for 30 years. That's probably not something that has changed. Something else is going on here.

And when I stop and think about what's going on new I think a lot of it has to do with rebuild near the beach and putting air conditioners in the houses that didn't used to use it or only as on peak.

Well let me go back. Actually that last graph. Here's more how we do the forecast. We break the forecast into what's weather sensitive and what's the base demand.

This is just a plot of the weather sensitive components. So it shows the megawatts per degree Fahrenheit, the weather sensitivity of the system. And it's been growing.

Now there's a quote of 5.7 percent from 2001 to 2006. And everyone screams, ah 2001 that was a recession. It's more like four percent from 2002 on. In any case, it's been growing, the sensitivity.

And I think this is where the growth is coming from. This is why we're going to continue to see over 1.5 load growth. This is a big part of it. As the weather sensitivity gets more as well as then you get more customers coming in here too.

I'm going to change the tone of my comments slightly here. When we turned over the report to our statistician he took a look at what the CEC had done and had a few technical comments.

Let me just, the first thing is the Divar variable. When we use it we multiply max times the min temperatures so that a high minimum temperature at night really increases the effect of temperature.

We found there's a lot of statistical

colinearity between Divar and temperature. And it's biasing your coefficients.

Point number two, first order serial correlation, that's what the statistician talked about. And point three goes along with it.

I step back and say, wait a second. What we had in 2006 and I'm sorry I didn't bring those graphs was the hottest summer in terms of energy that we've ever seen.

So it was the second hottest June in terms of average daily temperature and the hottest July. The July was three and a half standard deviations above normal, the average temperature.

Also in early 2006 we had a rate increase. And from state law for residential customers you weren't allowed to put any increase in the baseline component, only in the top tiers.

Well that sort of, and the increase was set to collect the right amount of money, assuming an average summer. Well Mother Nature conspired and gave us six to eight weeks of continuous hot temperature.

People in the high usage range who have big air conditioners, their bills soared. And they started going into what I'll call perhaps rate shock might be a little too exaggerated but they started seeing really high bills.

And by mid July they'd all gotten a June bill and started to get July bills. They were starting to do something. And what we found is they cut back in everything except their air condition use.

They cut back in air condition use. But they cut back in base load we think too. In other words, turn off the lights kid. keep the refrigerator closed. That bill was just too high. But we still want to be comfortable.

What points two and three here would be. They can also be explained by the weather sensitivity was higher in June and through the first part of July. And then by August the weather sensitivity actually dropped.

Because people were really trying to cut back on their electricity after they had already gotten this humongous bill. How can they try and save some money.

So we think that in the last half of summer that people were probably cutting back on their usage. And we've seen some statistics that showed that, yes, they did.

Also the temperatures cooled off. So it gave them less, it helped on that too. So points two and three here are what's printed is statistical. I think actually what went on was something else.

It's consumer behavior switched as the bills kept coming in through the middle of July and the end of July. And then our peak was in, on the 24th, 25th of July. So it was near the end of July.

And everyone had gotten a high bill. If they were air conditioner users, it was a high bill. Now the low use customers didn't see any increase. No increase in bill, no increase in usage. Those rates were frozen.

Point four, Saturdays and Sundays, we advised the staff to use a separate variable for Saturday, a separate variable for Sunday and a separate variable for holidays.

We find that we get hundreds of megawatts of difference between those coefficients rather than combining them all as one. It might not be work with your model but that's what works with ours.

Point five is the same point I brought

up before. There is no discussion that 1.5 is still a valid number.

Now in our 2007 IEPR Lynn we sent you recorded data up through the middle of April, hourly loads. I don't know if you've looked at those hourly loads compared to the same period of 2006 versus 2007.

If you haven't then I would urge the commissioners to ask the staff for what is happening out there right now.

I can say we're growing a lot faster than 1.5 percent. And now that's the winter and you're going to want to do some weather adjustment. But even that we can say is quite a bit faster.

So we pull off the ISO loads hourly everyday and analyze them and forecast those. And through the third week in May the ISO was growing 3.2 in 2007 over 2006. So that's the whole ISO service area.

Edison I think is a little bit on the higher side of that. So I think that's something you need to know that when you're judging how to slice this baby, how to divide it, how to pick this forecast, that the load growth, something is going on out there.

PRESIDING MEMBER PFANNENSTIEL: I'm sorry what load growth, oh it's a four percent that you would suggest the staff use?

MR. CANNING: Yes, yeah, we're looking at more like three and a half percent for the next few year. But something higher than one and a half, definitely.

And I could say, we are seeing something higher than one and a half. Now what will happen in the summer is still, there's uncertainty about that.

And the last point I brought up before. The staff has actually has got the right numbers. They show a 100 megawatt growth between 2005 and '06 which, you know we had 1.5 percent customer growth. We had 2.5 percent sales growth. A lot of that was weather.

There's more things going on that indicate that peak demand should have grown. So 2006 in all my years of analyzing weather which is over 35 now at Edison, it was the hardest summer to weather adjust. It just didn't seem to make sense.

Lynn can I have you come up here and

pull page nine of your presentation on the Edison forecast.

ASSOCIATE MEMBER BYRON: While she's doing that may I ask, the 1.5 percent customer growth, that's number of meters?

MR. CANNING: Yeah, that's number of customers active meters. It's the number of meters also is very close to that. It was, it slowed down with the building turn down. But it's still in the 1.4 percent range.

ASSOCIATE MEMBER BYRON: Can I also ask, going back to your, you don't have to go back to it, but back on slide four you, sources of differences SCE's long-term procurement plans shows a 2.8 percent growth. Does that incorporate the A/C cycling programs, demand response, energy efficiency?

MR. CANNING: No, that only includes, no it doesn't include any of the demand response. That's considered a supply variable.

ASSOCIATE MEMBER BYRON: Thanks.

MR. CANNING: No, not 19, number oh no. I'll show you what I want.

MS. MARSHALL: Which one? The first one?

MR. CANNING:   Yes, this one.
MS. MARSHALL:  Okay.
MR. CANNING:  Okay Lynn, I'm going to ask you to do a little volunteer for me.  Go up there and point to the two data points, well first you might point out, what was the peak day for the black point.  You know which one it is?
MS. MARSHALL:  Uh-hum, right.
MR. CANNING:  Since I don't have a little pointer here, if you could just go point --
MR. GORIN:  There's a pointer in the drawer.
MS. MARSHALL:  Oh, actually that drawer was a mess.  If you can take the mess.  Okay, maybe I can help you with that.
MR. CANNING:  Okay, so we got, that's the actual peak day.  Now if you move to the left about an inch from here, now further.  Okay, those two dates.
MS. MARSHALL:  Uh-hum.
MR. CANNING:  Those are two days that, you know, it's going to be interesting.  So their peaks are eyeballing us at somewhere around 22,500 looks like from the graph.
And at a temperature of, and it's kind

of hard from the parallax here, is it about 95 degrees, 96 degrees?

MS. MARSHALL: Yeah, uh-hum.

MR. CANNING: So if you took those two days and say, well what if we weather adjust them up to what would be on the peak day. In other words take an actual day and say, what would the people have done at 102 degrees or whatever your peak day temperature is.

At 400 megawatts a degree and you add five degrees on, you're going to add a couple thousand megawatts here. So actually we had some days that if you weather adjusted those days up to the peak day, the customers were acting in a behavior in that point in time as if the weather adjusted peak would be more in the range of 23,000 not twenty-two four.

So there, as I said, 2006 is a tricky year to weather adjust. I think the staff numbers, the starting point is low, the growth rate is low, both of those contribute to a low 2008 number.

And we recommend the Commission look at something than what the staff is recommending.

MR. GORIN: I'd like to make a comment

about that chart.

MR. CANNING: Sure.

MR. GORIN: If you put a trend line however statistically incorrect it may be through both of those years there's no discernible difference that trend line, between each trend line.

The point is that for the most part those temperature load relationships fall on top of each other. The greatest difference is in 2005 there was a lot more lower temperature occurrences in Edison than there were in 2006.

MR. CANNING: That's true, 2006 had a lot of hot days.

MR. GORIN: And there can be rate shock from people paying higher bills. There can also be acclimation to hot weather. If it's a 100 degrees for two weeks and then it's 80. It feels good.

Rather than if it's 80 for two weeks and then it's a 100 for two days, right?

MR. CANNING: Yes. Any other questions?

PRESIDING MEMBER PFANNENSTIEL: None for me, Jeff?

ASSOCIATE MEMBER BYRON: Well I'd like

to, the does the staff have the other responses with regards to why we're seeing such a big difference between the projections that SCE is putting up and our own? I noticed you had some additional backups. Did you want to go into any of those?

MR. GORIN: Sure.

MS. MARSHALL: Well I think this slide just gives a little different perspective on or a longer term perspective on the growth we have seen in recent years. A lot of the growth 2001 is merely bringing us back up to the trend we were on before the energy crises and before the end of the tech bubble.

So if you look, this is our megawatts per degree of relationships. If you look at the trend just of the load, the growth in that megawatt per degree since 2001, yeah it looks like really rapid growth.

But starting with the trend, the pink lines, back beginning in 1993 what it looks like actually is just that we've been moving back up to the temperature response trend that we were on previously.

And now that's starting to level off. I

think Art's point about maybe this load growth was associated with low interest rates and refinancing, remodelling. That's I think a good hypothesis. The question is whether in the current environment we're going to expect that to continue over the next couple of years.

So that's all.

ASSOCIATE MEMBER BYRON: I was going to ask Lynn if you might also that you've looked at this load factor trending that Mr. Canning has identified on his slide seven where they saw a prolonged ten year drop in load factor then it flattens out for a number of years and now, I think he's characterizing that we're beginning to see another significant drop. Have you looked at this load factor kind of data?

MR. GORIN: There's a historic load factor report that was written for the last IEPR that's on the website somewhere. The drop starting in '69 I think is the discovery of central air conditioning.

ASSOCIATE MEMBER BYRON: Right.

MR. GORIN: And then there's a levelling out when it was relatively fully saturated. The peak around 2000 is the, the uptick around 2001 could be associated with the energy crises and people not using, afraid to use their air conditioners.

And I would argue that the drop in the load factor since then is people returning to normal business as usual in the use of their air conditioning. And maybe it's true that people are remodelling their house.

We have a fairly large saturation of air conditioning in the coastal region of Southern California Edison's territory. And those people have a really low load factor.

MR. CANNING: If I could just bring up, if we look at the slide on the board here. Lynn has the long-term trend from '93 on. And if you look at, starting at '95 which was as we were coming out of the aerospace recession, '95 is the last dot 2006 of the pink?

Yeah, eleven years of upward growth through a business cycle there. That's a whole different trend. So I think that's what we're thinking is continuing.

PRESIDING MEMBER PFANNENSTIEL: Thank you Mr. Canning.

MR. CANNING: Thanks.

PRESIDING MEMBER PFANNENSTIEL: Melissa, Suzanne do you have a comment or questions? Thank you.

MS. MARSHALL: Would San Diego like to make any comments? Okay, well we'll just leave that.

MR. BONDER: Okay, now we're fine. Tim Bonder with San Diego Gas and Electric Company.

MS. MARSHALL: You'll need to speak closer to the mic.

MR. BONDER: I'm sorry, okay. Are we on now, okay. I'm Tim Bonder from San Diego Gas and Electric Company in the forecasting area. And I'd like to make a few comments.

We have nothing to present today. But I'd still like to make a few comments. Staff, I guess I'd also like to say that we've got no rocks to throw at staff's forecast of our area for years.

PRESIDING MEMBER PFANNENSTIEL: That's comforting.

MR. BONDER: You know 2007 through 2008, as a matter of fact the forecast that we submitted as part of the 2007 IEPR process the comparison that staff is making of their forecast for this process is to the forecast that we filed for the 2007 IEPR.

The comparison that staff is making of their forecast for this process is to the forecast that we filed for the 2007 IEPR. And we're within, oh, 33 to 49 megawatts of each other which is one percent or less.

So like I said with that small of a difference for those years 2007, 2008 we're pretty satisfied.

I'd like to mention that two years ago when we were making our forecast presentation for IEPR 2005 staff, CEC staff and SDG&E staff was directed by Commissioner Geesman to share date, share weather data and to dialogue.

And I'm kind of happy to report that over those past two years we've been sharing data. We have shared our weather history data with staff. We've shared our humidity data, our cloud cover data, our temperature data and we've dialogued with them for two years now.

And I can't say that staff has incorporated all of our techniques into their techniques. But the bottom line is even though we're still approaching it slightly different, the bottom line is our numbers are pretty close.

Again, we submitted our IEPR 2007 to this process and will be reviewing staff's IEPr 2007 shortly. And so I just hope that we can continue our dialogue and hope it continues to go in the same direction. Those are our comments.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much. Melissa to pass on to Commissioner Geesman that, in fact, his directions worked at least as far as San Diego Gas and Electric goes.

MS. MARSHALL: Okay. Is there any other utilities want to make any comments on this matter?

MR. ZETTEL: Nick Zettel from Redding Electric Utility. I have a few things I wanted to run through real quick.

One is based the annual growth number, that percentage number. Two is Art's load factor chart which Redding shares the declining number which the trend doesn't look good for either Art or myself. And three is a concept of load duration. So I'll just start with number one, the annual growth.

Redding is historically, I'd say for the last 20 years used past experience, past temperatures which staff has done a great job. But we also incorporate some of the economic measures or econometrics.

And something that Redding noticed last summer was we've had huge housing growth, residential growth in the area, just like Sacramento, Folsom, Natomas. The housing starts that we've seen this year are dramatically down.

So when we were forecasting in 2003, four, five, six the numbers were getting pretty high. And now we've kind of had to go back to the drawing board and take a look again at what has happened to the growth.

Number two is, what has happened to migration, residential and particularly commercial, industrial as some of the major industries are pushing either off seas or into other states due to all kinds of issues from Worker's Compensation to energy costs to what have you.

And one of the other issues we look at is competing sources for income. And one of the other big driving factors there is gasoline costs are going up, food costs are going up, mortgages are higher so how much electricity is going to be used compared to in the past.

So those are some of the econometrics that we look at to help develop our growth numbers versus just historical trending and regression.

Getting to load factor which really has a lot to do with annual growth, something that we have noticed is homes and businesses are a lot more efficient than they used to be, energy efficient not capacity efficient.

Energy Star appliances use a lot less power. Title 24 is a lot of efficiency improvements. But everybody it seems like is getting an air conditioner installed and sometimes two of them.

And Redding did this study that we were looking at an air conditioner and we actually plugged it into a monitor and monitored the temperature, the refrigerant as it got hotter and hotter and hotter.

And what we noticed is a five ton air conditioner which is pretty common size for a residential home which usually demanded about five kilowatts or one kilowatt per ton was actually demanding somewhere around ten to twelve kilowatts on that real hot day last summer.

And we talked to some engineers about it and they informed us that these new air conditioners have higher pressure refrigerants which get hot and expand and make it a lot more work for the compressor to do its thing.

And the bottom line for me is without getting too scientific is these air conditioners the new high SEER, high EER air conditioners are efficient on an energy basis but when it gets real hot in that one day and those three hours it really hurts your demand which really hurts your load factor. Because load factor is based on one number over a year.

Which gets to load duration. And load duration is simply the number, you take the 8,760 hours over a year and you look at how much capacity was demanded and I call it my 25 hour problem in Redding. My load duration, I will jump from 200 megawatts to 250 in 25 hours out of 8,760.

And when we start to look at what can we do to offset this. Do we raise our forecasts? Do we buy more peak capacity? Or can we shift that to some other hours? We are looking at all of those.

But I think that staff has done a great job. And I like the insight from the IOUs, Edison and San Diego and PG&E. And I just thought throw in some economics and some of the load factor issues that we've been seeing in Redding. I appreciate it.

PRESIDING MEMBER PFANNENSTIEL: Thank you very much for sharing those, interesting.

ASSOCIATE MEMBER BYRON: If I may before you leave I, this is news to me with regard to a five ton A/C unit. I mean it doesn't saturate on its use of electricity.

You're saying during very high temperature differences it can use up to twice the kilowatts.

MR. ZETTEL: Yes.

ASSOCIATE MEMBER BYRON: Is there anyone here on staff that can, this doesn't really have anything to do with today's workshop except that it might help to explain why we don't see saturation on A/C when we get these really high temperatures.

Is there anyone here on staff that could talk to this issue? Okay.

PRESIDING MEMBER PFANNENSTIEL: I don't

think, we'll talk to the appliance people.

ASSOCIATE MEMBER BYRON: Yes, we're going to definitely look into that. Thank you very much for coming and for your input.

MR. ZETTEL: No problem, thank you.

MS. MARSHALL: Okay, is there anyone else that would like to make comments? No. Do you have any more questions on this topic or can we move on?

PRESIDING MEMBER PFANNENSTIEL: I don't. Melissa? Melissa or Suzanne? Now I don't know how long we're planning, I don't mind going into the supply and demand outlook. Should we start that now or take lunch now? How long will this be Denny?

MR. BROWN: I've got 15 to 20 minutes of comments. And then just depending on the --

PRESIDING MEMBER PFANNENSTIEL: Why don't we go ahead.

MR. BROWN: Thank you. Good morning, I'm Denny Brown with the Electricity Analysis Office and I will just do a quick overview of our Summer 2000 (sic) Electricity Supply and Demand Outlook, briefly talk about the purpose of the report and the workshop.

I discuss some changes from our 2006 studies. Present the 2007 outlooks in both the deterministic and a probabilistic format. And just briefly cover some resource assumptions. And then I really want to get into some next steps for 2008.

So why publish a report on the 2007 outlook and have a workshop on May 24th when 2007 is upon us? We've actually presented the results of this three times now.

We presented it in December to the EAP. Commissioner Byron presented it to the Assembly on March 29th. And then it was updated and refreshed for the EAP two days ago.

So we just really wanted to formalize the documentation and the assumptions that we used in the outlook.

Second and most important at this point is we're starting our 2008 and our five year, excuse me, 2008 and five year outlook. And we wanted to throw out some topics that we'd like to add to our analysis as well as solicit additional topics that you would like us to incorporate and some suggestions on how to incorporate those.

The 2007 deterministic tables no longer

include the operating reserve margin calculations under expected or adverse conditions. Staff felt like it's too difficult to forecast on a single point or two point forecasts with any certainty a supply or a demand scenario.

We do continue to calculate deterministic tables up to the planning reserve margin and this planning reserve is similar to what is used in resource adequacy proceedings at the PUC.

Second, we've added probability analysis for the CA ISO and the NP 26 regions, sub-region of the ISO, to go along with the SP 26 region that we did in 2006.

Again, the summer 2007 deterministic tables present only to the planning reserve margin. And we have four tables that we do, statewide, CA ISO, North Path 26 and South Path 26.

Our probabilistic analysis only covers the three regions of CA ISO, NP 26 and SP 26. Because the statewide system is made up of several control areas and doesn't operate as an integrated system we do not include a probabilistic assessment for that.

This chart just provides a summary of all four regions in the, to the planning reserve margin in the deterministic format. This is the peak month for each of these regions. So NP 26 would be July, SP 26 is the late August/September time frame and ISO and Statewides, they are both August.

Here we see SP 26 once again has the lowest planning reserve margin. However it still exceeds the 15 to 17 percent required by the resource adequacy.

And this just breaks out these tables into a monthly format. And I would like to point out on the, looking at the CA ISO and when I get to the SP and NP regions I've included the complete range of demand that we've included in our probabilistic analysis. Complete range of forced outages assumptions as well as transmission outages.

And again the same thing for NP and SP 26 with ranges at the bottom. So moving into a probabilistic assessment from a deterministic one we looked at the factors on this chart to. These are the major factors that we see affecting supply adequacy.

The factors that are in gray are the ones that we've added probabilistic assessment or we've randomized. And basically how we do this is we take our supply estimates based on the deterministic tables and we, in one case we will randomize a generation outage, randomize a level of transmission outages and we'll come out with a net supply.

Then we'll capture a random demand value based off 54 years of historic temperature. And we looked to see what the operating reserve margin is for that one draw.

We then repeat this for 5,000 draws so we can get a complete range of operating reserve. And the operating reserve values are summarized by the blue line on this chart. This particular one is for the California ISO.

Now at the point of the seven percent operating reserve margin we include additional resources which have the effect of reducing demand. And that's the demand response of what's traditionally triggered by a stage one event called by the ISO.

And then again at five percent we get the stage two which triggers voluntary demand response as well as interruptible load programs. And I'll, I know the numbers get pretty small down there at the bottom of this chart so I'll summarize a little bit in a couple of slides later.

The same information for the NP 26 region. Again very low probability, a very low risk associated with a stage three, involuntary load curtailment event.

And SP 26, we do see a higher risk level of, all three levels of calling demand response, calling on voluntary interruptible load programs, as well as a firm load curtailment possibility.

And perhaps an easier way to read these graphs, we've included this bar chart so looking at California ISO we've got about a 14 percent probability that we're going to need voluntary demand response this summer. And that, again, for each of the three regions.

And then finally the one that really draws our attention is the loss of firm load. And so for -- The ISO and NP 26 both have less than one percent probability of loss of firm load this summer, SP 26 it's 3.8 percent.

I've included the WECC planning standard on this chart. Just one caveat is we're looking at one day, peak day analysis and the WECC loss of load probability is an eighty-seven, sixty requirement.

Just going through some of the resource assumptions. These haven't changed a lot. This is as of August 1, 2006 for the existing. So we just incorporated all the additions we saw from August 1, '05 to '06. And that's the only change in this table.

The SP 26 region does include a little over a 1,000 megawatts of generation physically located in Baja. And the non-California ISO totals include all hydro and thermal resources.

These are the additions that we are expecting going back to August 1st of last year. Many of them are already on the line.

A couple of them that we are keeping a close eye on are in the Edison service territory, the Long Beach Repower as well as the Edison Regional Peakers that were approved by the PUC last year. This value actually for the peakers includes four of the five that were approved.

And also we're keeping an eye on the Roseville Energy Park as well. And the reason we're kind of watching those is because they're expected on line. We say here in August, but our break point is the first of the month. So anything that comes on after July 1st counts as August 1. So they may or may not be available during a summer peak.

ASSOCIATE MEMBER BYRON: Mr. Brown.

MR. BROWN: Yes.

ASSOCIATE MEMBER BYRON: Two questions. One, the megawatt additions, are those derated in some way?

MR. BROWN: Yes thank you. This is the summer dependable capacity derate.

ASSOCIATE MEMBER BYRON: And when is the last time you got an update from either the ISO or Southern California Edison with regard to the on line date for those peakers? I know we checked on this just before we gave the presentation to the Assembly. Have you checked since then?

MR. BROWN: I believe it was right after the Assembly they were still on target. I don't remember the exact date. But they were still on target for four of the five.

And the EAP it was brief. That Long Beach was on target. But I didn't catch the update on papers. I can check into that.

ASSOCIATE MEMBER BYRON: Okay.

MR. BROWN: Here are the net interchange assumptions for each of the four regions. A couple of things I'd like to point out. We're showing in the California ISO as well as the SP region, we show 1,000 d megawatts coming from LADWP's control area.

That's not to say that LA is in a surplus situation. A lot of that is WILL power coming from InterMountain Power that belongs to the utilities that are within the CA ISO control area as well as some of their intertie on the southwest link.

And also on the NP to SP 26 regions we show path 26 values. And the way this shows on this analysis is the 3,000 megawatts is always moving north to south. I'll have some additional comments on this a little bit later. And we think this needs additional review for the 2008 report.

And just to support our assumptions for imports that we're assuming out of the Northwest. We assume about 6,000 megawatts of imports coming from the Northwest.

So we went to the BPA Pacific Northwest

Loads and Resources Studies for 2007 and looked at their surplus capacity given various hydro conditions out of the Northwest.

And in order to meet the 6,000 megawatts that we need, we actually need about 5,500 megawatts of surplus because in their analysis they are counting their firm sales to California.

So even looking at a 1937 water year, which was the driest water year recorded, there is sufficient surplus capacity in the Northwest to meet our import assumptions.

ASSOCIATE MEMBER BYRON: If I may interrupt you one more time. Do you recall right off because I don't, what our surplus, what we indeed got last year on say, July 24th?

MR. BROWN: I don't. I don't recall the exact number but I'd have to go back and look at the Northwest tie. But I do know we were maxing out the Northwest ties.

ASSOCIATE MEMBER BYRON: That's right.

MR. BROWN: And actually it may have been a little bit above the 6,000 that we were counting.

ASSOCIATE MEMBER BYRON: Right, that's my recollection as well. I was just wondering if you remembered the quantity.

MR. BROWN: I don't have the exact number on that.

ASSOCIATE MEMBER BYRON: That's okay. Thank you.

ADVISOR JONES: And Denny, I was also going to ask what kind of a water year is Bonneville having this year?

MR. BROWN: They are at 90 percent of normal.

ADVISOR JONES: Okay, great, thanks.

MR. BROWN: The demand response and interruptible programs, this is exactly the same chart we used in 2006. We do know that the PUC has approved several programs.

Edison informed us of their status during the EAP two days ago. But unfortunately we just haven't had an experience to see what kind of dependable capacity we can count on out of these interruptible programs.

One thing to note is that if one or two of the Edison peakers don't make it on line that summer, for this summer, that possibly some of their additional demand response or their A/C cycling programs specifically can help make up for some of that capacity loss.

PRESIDING MEMBER PFANNENSTIEL: Excuse me, on the question of the dependable capacity from the air conditioning cycling?

MR. BROWN: Yes.

PRESIDING MEMBER PFANNENSTIEL: I mean they have a long, a lot of experience with air conditioning cycling. Are you not using that?

MR. BROWN: They do and we use that to come up with the value that's here.

Unfortunately I think as reported at the EAP on Tuesday was, they're forecasting 300 megawatts to be enrolled but to date they've only enrolled 75 megawatts. So what they actually get between now and the peak day would be much more difficult to project.

PRESIDING MEMBER PFANNENSTIEL: I thought that they had said at the EAP that they're on track to get the 300 megawatts. That's my confusion. So they are still saying they are but they just don't have it on yet?

MR. BROWN: That's correct. My understanding was they have 75 enrolled and they are on track, they're saying on track to get 300 by summer.

PRESIDING MEMBER PFANNENSTIEL: Okay.

MR. BROWN: Moving to the Summer 2008 and Five-Year Outlook Topics. Some of the topics that we'd like to add for our study, the first one is wind variability.

Looking at 2003, 2004 data we saw wind performing at two to three percent of main plate capacity at, during the peak hours.

Last year the average during the peak week of July was around 12 percent and we actually saw on the peak day on the 24th it was up around 16 percent.

So this is an item that we'd like to additional study. And we'd also like to solicit any input that the stakeholders may have to help us with this, with this task.

We'd also like to work on developing some long-term demand variables for probabilistic study. And this would allow us to move not just present the summer 2008 forecast in a probabilistic manner but a five year forecast in a probabilistic manner as well.

Some of the items that we need to randomize to do that would be economic factors as well as demographic. And many of the comments that were brought up, topics that were brought up during the demand portion of this workshop.

We'd also like to study planning reserve levels to determine associates loss of firm load risk. And what we mean by this is we'd like to, we haven't determined the best way to do it yet is either reduce resources in a particular region to get down to a 15 percent planning reserve and then run probability calculations to see what the loss of load probability is at that level.

Then do the same thing at 17 percent. And this would go along with what we already project for the whatever the current planning reserve level is for a given region.

One of the things, there are several hot topics with the environmental issues and we're attempting to study how they're going to impact the overall system.

Recently, once-through cooling, power plants that use once-through cooling technology, there's been back and forth a federal regulation as well as a possible state policy regarding these plants.

And we need to determine, one, if they're capable of being retrofitted to meet the once-through cooling standards that may come out on the first of the year and if not what the impact of that would be.

We're also looking at some of the greenhouse gas legislation that's coming forward and trying to see how that will impact reliability over the next five year period.

And finally as I mentioned before, the 3,000 megawatt path 26 assumption. The next slide shows the actual summer 2006 path 26 net flows. And as you can see there's a lot of variation from day to day on this 3,000 megawatt assumption.

And in fact on July 24th and July 25th we saw less than 1,000 megawatts flowing north to south. So this would have a great variation, a great impact on the probability analysis of both NP 26 and SP 26 if there was some type of coincident event.

We experienced a 1 in 26 in northern California, possibly a 1 in 26 in northern California, and as Lynn pointed out a 1 in 8 in southern California. Had it been above a 1 in 10 level in both regions it would have been interesting to see what these flows would have been. And that's part of what we need to try and determine probabilistically.

And so especially for the transmission operators, if we could get some comments input on this assumption as well. Is there any questions?

PRESIDING MEMBER PFANNENSTIEL: Good presentation, thank you. I think no other questions from up here.

Sylvia how would you like to proceed now? Do you want to get comments from the utilities? We may be able to just move right in rather than stopping for lunch it looks like.

MS. BENDER: Yes I think so.

PRESIDING MEMBER PFANNENSTIEL: We've gone through the heart of what we have.

MS. BENDER: I don't know that there are any other presentations that are planned at this point so I think we could move directly to the public comment period for both people in the audience and on the phone perhaps.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Should we start by asking whether the utilities have specific comments on the outlook. Anything that doesn't work, anything we should pay attention to.

MR. MINICK: I'm Mark Minick from

Southern California Edison. I'm manager of resource planning. I want to thank Denny for the presentation. Den and I have worked quite a bit together on some of these things.

And first let me answer some your questions. Yes, four out of the five peakers are right now scheduled to be on line by August 1st. We send a monthly report to the CPUC. Our last report indicated that four out of the five would be. The one in Oxnard we're having a lot of difficulty signing and licensing.

ASSOCIATE MEMBER BYRON: And do you recall what the megawatt total is on those four out of five?

MR. MINICK: Denny actually used the numbers that I gave him.

ASSOCIATE MEMBER BYRON: Thank you very much.

MR. MINICK: We did rate the units. They're rated at about 47 to 48 megawatts nominal. But that's at isokinetic conditions.

At the temperatures and regimes they'll operate at peak we use about 44 megawatts apiece. They'll vary slightly different at each site.

Regarding the A/C cycling. We will have

at least 175 megawatts of A/C cycling I think on and operational by this summer. We were supposed to get 300. I think we're trying to get 250. I'm not sure realistically we'll get there. So I'm saying that's a certain minimum we expect right now.

We agree with Denny that probability analysis is a better way to go I think in the long run. I think our problem right now is when you do probability analysis you're going to have to use it to come up with some megawatt numbers.

Because we are under a guidance by you and the PUC to make purchases. And we don't buy to probability purchase analyses, we buy to megawatts. So whatever you do I encourage you to come up with a megawatt need in the future that we have to meet, not a certain probability.

Because I'd like to understand the probability analysis better. And that's an issue of confidentiality in some cases.

I'd love to work with Denny and the staff some more on what data they're using and why. In many cases the data comes from the ISO so it might be confidential. We haven't seen all the data in the details. We may not be able to see it. But I'd just like to understand it.

When you use forced outage rate data are you using all peak hours, just the top peak hours of the day or the month or the year? How are you utilizing that forced outage rate data and some of the other data that were use in the probability analysis? There are different ways of looking at it and I think we can work with that.

ASSOCIATE MEMBER BYRON: Excuse me for interrupting you. I think --

MR. MINICK: Sure.

ASSOCIATE MEMBER BYRON: perhaps a naive question. Is some of our data confidential, Mr. Brown? Some of the data that we use we cannot share?

MR. BROWN: Yes, we do get a significant amount of data from confidential ISO subpoena.

ASSOCIATE MEMBER BYRON: Okay.

MR. MINICK: And we understand that. There might be a way to aggregate it or use it so we can understand it a little bit better.

ADVISOR JONES: Right. That's the argument we keep using with you.

MR. MINICK: Yes, yes. We understand the argument, okay, and we agree to it in some cases, okay.

The wind probability needs to be modeled correctly and I agree that wind can vary between 3 percent and possibly 15 percent output at the time of the peak. But it changes every year and I don't think we have a way of predicting what it's likely to be in the future at the time of the peak. So I think we need to be careful or model really well what this can amount to.

Because as you know, you want 33 percent renewables, possibly. This could be 4,000 to 12,000 megawatts of wind. And if we've got 12,000 megawatts of wind and there was a 10 or 15 percent difference on peak it could mean a huge difference to how many megawatts we need to supply our customers.

And my last comment is simply one that you already know. If we are going to err let's err on having a little more than a little less. Because the ramifications of having too few resources are blackouts. The ramifications of having a little bit too much means we buy a little less in the future.

PRESIDING MEMBER PFANNENSTIEL: That's fine, I thank you for that. I would suggest that somebody from Edison should have a conversation with President Peevey of the PUC since he still thinks that you are going to have 300 megawatts of air conditioning cycling this summer and was rather critical that we hadn't included all 300 megawatts. Somebody better update that information with him.

ASSOCIATE MEMBER BYRON: I plan to update him on that information.

PRESIDING MEMBER PFANNENSTIEL: Good.

MR. MINICK: I think there is a report that goes to the PUC monthly regarding our progress on those particular plants.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Any other comments on utilities or otherwise?

MR. HATTON: Hello, my name is Curt Hatton from Pacific Gas & Electric. And I'd like to start with commending the CEC for starting to look at a probabilistic approach. I think it provides a broader perspective of supply and demand and I think it will help in discussions of the supply and demand situation in California.

I'd also like to continue to ask for coordination and consultation with the PUC, the

CEC and the CA ISO. I know we've trying to do that. I think that's a good, another good perspective as we move forward, to try to have consistent assumptions and consistent methodologies.

I did have one question that came up as part of your outlook. I know you had -- On the CA ISO NP 26 you had maximum and minimum demands. And one question I had was, do we know what the NP 26 demand was in the ISO? Do you happen to know what that is?

MR. BROWN: For 2006?

MR. HATTON: For 2006, yes.

MR. BROWN: I would defer to our demand office on that one.

MS. MARSHALL: Twenty-two, 7, 26.

MR. BROWN: That's 22, 7, 26.

MR. HATTON: Okay. Well I just wanted to make sure that I was understanding how in comparison of the minimum/maximum, in the probabilistic range.

A couple of comments that I had, one was on the involuntary load curtailment. I agree with the CEC that load curtailment will occur before planning reserves come down to a zero percent level. However, as the ISO has when they declare a Stage three, the question is, you know, what level they declare that at.

The ISO in their summer assessment when they were quantifying the probability of a stage three level, looked at when reserves drop below three percent. And that's more consistent with what PG&E is using.

Moving to another topic. Your staff has requested comments on the 2008 summer outlook as well as the five year outlook. And as Rick Aslin pointed out, demand is a big driver in potential load curtailments in perhaps meeting demand. So I would again look at demand uncertainties.

You had pointed out earlier that you're also looking at the longer term demand variables. I'd also like to add any other demand variables, including perhaps just model forecast error, which would increase the range of potential loads.

It is also important to consider that beyond just the 1 in 10 low, which is a particular point forecast, when we're looking at the supply and demand situation on a probabilistic manner it is the entire curve. So I would also have you, you know, relook at how the curve is through the entire spectrum from, you know, basically the 50 percent all the way out to the 100 percent.

A couple of other points. You brought up interchange and looking at the path 26 interchange. Another topic I'd like to look at also is an interchange and that's the WAPA to NP 26. I think we'd like to maybe reexamine how we've come up with that and perhaps look at that.

I don't know whether you are going to be looking at in the longer term how it -- perhaps how the utilities or different LSEs might be meeting their RPS requirements. But if we are then we might have a question as to the mix of technologies and that would affect the supply and demand.

You brought up environmental impacts and once-through cooling and its effect on potential plants. Again this goes to more of the longer five year outlook, but there are other reasons why plants may or may not continue to operate and that would also have an effect. So depending upon what your focus is that might be another topic that could be of use in the five year outlook.

And that's all the comments I have. Thank you.

PRESIDING MEMBER PFANNENSTIEL: Thank you. Other comments? Anyone in the room?

Anybody on the phone? Is there anybody on the phone who would like to make comments?

All right. Final comments, Commissioner Byron?

ASSOCIATE MEMBER BYRON: Having not participated in one of these peak demand forecast workshops I found it very informative. I would like to certainly thank the staff. But most of all I'd like to thank those that went out of their way to be here today to provide us with comment input. I think it will be very helpful to the IEPR.

PRESIDING MEMBER PFANNENSTIEL: It's one of the building blocks in the IEPR so thank you all very much. Good day.

ASSOCIATE MEMBER BYRON: Thank you.

PRESIDING MEMBER PFANNENSTIEL: We'll be adjourned.

(Whereupon, at 12:05 p.m., the Committee workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, JOHN COTA, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 4th day of June, 2007.